BEFORE
THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA
DOCKET NO. 2019-185-E
DOCKET NO. 2019-186-E

IN RE: South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) - S.C. Code Ann. Section 58-41-20(A)	)	**SURREBUTTAL TESTIMONY OF ED BURGESS ON BEHALF OF SOUTH CAROLINA SOLAR BUSINESS ALLIANCE**

Q. Please state your name, occupation, and business address.

A. My name is Ed Burgess. I am a Senior Director at Strategen Consulting. My business address is 2150 Allston Way, Suite 400, Berkeley, California 94704.

Q. Are you the same Ed Burgess that offered direct testimony in this docket?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to certain issues raised by Duke Energy Carolinas LLC and Duke Energy Progress LLC (collectively, "Duke") in the rebuttal testimony of Mr. Glen Snider, regarding the companies' avoided cost calculations.

I. Incentives & General Issues

Q. What does Duke's rebuttal testimony claim regarding the utility incentive to limit QF deployment through low avoided cost rates?

A. Duke argues that it has no incentive to limit QF deployment through low avoided cost rates for two main reasons. First, Duke argues that solar QFs have "little impact on the need for future generation," [1] and therefore do not displace utility-owned generation. Second, Duke argues that fuel costs displaced by QF power are "a pass-through expense paid directly by Duke's customers" and therefore "Duke is financially indifferent to purchasing any of these fuel sources." [2]

Q. Do you agree with either of these points?

A. No, I do not.

[1] Snider Rebuttal, p 6.
[2] Snider Rebuttal, p 6.

Q. Regarding the first point – that QFs have "little impact" on the need for utility-owned generation -- does Duke claim that solar QFs have *zero impact* on its needs for future generation?

A. No. While Duke claims that solar QFs have "little impact", the Company notably does not claim that these resources have zero impact on its needs for future generation capacity. Thus, Duke admits that solar QFs do have *some* impact on future generation needs; it is simply a matter of how much. It is worth noting that this purportedly small impact is largely determined by Duke's own assessment of solar capacity value (which SBA disputes) as well as Duke's own evaluation of future capacity needs according to its 2019 IRP Update (which has not been approved by this Commission). Furthermore, Duke seems to ignore solar QFs that include energy storage, which can provide enhanced capacity value, even during non-daylight hours, and could have substantially more impact than standalone solar on future generation needs. Even if Duke's conclusion were true (i.e. that solar QFs have "little impact" on generation needs), this conclusion would not also be true for QFs with storage, which can tailor their output towards the hours with highest loss of load risk (e.g. winter mornings). Finally, Duke's argument leaves out utility-owned generation that might be justified primarily on the basis of lowering overall energy costs, rather than incremental capacity needs. To the extent QFs reduce Duke's future energy needs, then they could have an impact on utility-owned generation resources.

Q. Regarding the second point – that Duke is financially indifferent to fuel or QF purchases that are directly passed through – what is your response?

A. I disagree. As discussed in my direct testimony, Duke's holding company has a robust natural gas transmission business and is actively developing new pipeline projects. Thus, even if natural gas fuel costs are a pass-through for Duke's retail electric customers, the overall demand for natural gas in the region could impact Duke's financial interests. Duke does not dispute this claim in its rebuttal.

Q. Do you agree with Duke's suggestion that you put forward the concept of the zone of reasonableness "in an effort to promote the Commission adopting higher avoided cost rates"[3]?

A. No. This concept was raised in an attempt to describe the de facto reality that there are a range of plausible avoided costs, and a variety of subjective decisions that affect the outcome within this range.

Q. Do you agree with Duke's assertion (page 11 of Snider Rebuttal) that this concept is "wholly inapplicable" within a ratemaking context like this proceeding?

A. No. The "zone of reasonableness" standard is not novel. It was derived from the "just and reasonable" standard and has been outlined in case precedent for decades. Jeff Makholm and Kurt Strunk of the National Economic Research Associates Inc. (NERA) discuss the standard and its usage in court decisions extensively in an article in the Public Utilities Fortnightly journal.[4] The authors specifically cite a number of decisions that have held the Federal Energy Regulatory Commission (FERC) to the "zone of reasonableness" standard, including one by the Public Service Commission of Kentucky.[5] An article by energy attorney Adrienne Thompson of Troutman Sanders LLP in the George Washington Journal

---

[3] Snider Rebuttal at p 11.

[4] Makholm, Jeff D., and Kurt G. Strunk. "Zone of reasonableness: coping with rising profitability, a decade after restructuring." Public Utilities Fortnightly [1994], July 2011, p. 18-22.

[5] See: Permian Basin, 390 U.S. at 797, 88 S.Ct. 1344; Pub. Serv. Comm'n of Ky., 397 F.3d at 1009.

of Energy & Environmental Law[6] further outlines case law precedent where the Supreme Court has noted the "zone of reasonableness" standard in utility regulation[7] subject to an "arbitrary and capricious" standard under the Administrative Procedure Act (APA).[8] The "zone of reasonableness" has also been incorporated into a new framework for FERC in deciding whether the base return on equity for transmission investments is just and reasonable. On October 16, 2018, FERC issued an order addressing four complaint proceedings involving the New England Transmission Owners' base rate of return on equity (ROE).[9][6] The order describes FERC's "proposed framework" for deciding whether an existing ROE remains just and reasonable in a complaint proceeding, which includes the establishment of a "zone of reasonableness."

Q. Would the adopting the "zone of reasonableness" standard violate either PURPA or Act 62 by creating QF rates that do not reflect the utility's actual avoided costs?

A. No. Actual avoided costs are unfortunately hard to determine because of a variety of different inputs that are projected. For example, there is no way to perfectly predict load

[6] Thompson, Adrienne L., "Preparing for the Energy Future by Creating It: What State Public Utility Commissions Can do to Promote Sustainable Energy Policies." George Washington Journal of Energy & Environmental Law, Fall 2016, Volume 7, Number 3. Link: https://gwjeel.com/wp-content/uploads/2017/01/adrienne-l-thompson-preparing-for-the-energy-future-by-creating-itwhat-state-public-utility-commissions-can-do-to-promote-sustainable-energy-policies-7-geo-wash-j-energy-envtl.pdf

[7] See, e.g., In re Permian Basin Area Rate Cases, 390 U.S. 747, 767 (1968) (citing FPC v. Natural Gas Pipeline Co. for the rule that courts are without authority to set aside any rate selected by the Commission which is within a "zone of reasonableness."); see also Fed. Energy Regulatory Comm'n v. Pennzoil Producing Co., 439 U.S. 508, 517, (1979) (citing Permian Basin Area Rate Cases for support of the rule); Fed. Power Comm'n v. Natural Gas Pipeline Co. of Am., 315 U.S. 575, 585, (1942) ("Assuming that there is a zone of reasonableness within which the Commission is free to fix a rate varying in amount and higher than a confiscatory rate.").

[8] 42 F.3d 659 (D.C. Cir. 1994); see generally Administrative Procedure Act, 5 U.S.C. § 706(2)(A) (directing courts reviewing agency orders to "hold unlawful and set aside agency action, findings, and conclusions found to be… arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law").

[9] Order 165FERC61,030 Directing Briefs re Vermont Transco, LLC Docket Nos.et al under EL11-66 et al. http://elibrary.ferc.gov:0/IDMWS/doc_info.asp?document_id=14712363

growth or commodity prices in 5 or 10 years. As such, models are used to approximate the avoided costs. Models are only a representation of reality and naturally insert uncertainty into the outputs. The “zone of reasonableness” standard recognizes the bounds of uncertainty in the avoided cost rates derived from the methodology that will be decided upon by the Commission.

II. IRP and Model Accuracy

Q. What is Duke’s response to my argument that its modeled avoided cost rates reflect biased methodological choices?

A. Duke argues that its methodological choices are sound because they are consistent with those already used in its integrated resource plan. This argument falls flat for a few reasons. First, there is no reason why the IRP itself could not be biased in favor of Duke’s corporate revenue goals. To this point, it is notable that Duke relied upon a 2019 Update to its previous IRP. Reliance on this 2019 update is problematic for several reasons:

- The 2019 Update was provided to parties in this proceeding only very recently (September 4th, well after Duke’s own testimony was filed and shortly before intervenor testimony was due) and has not been reviewed or approved by the PSC.
- The 2019 IRP Update does not reflect the accelerated retirements of five coal plants announced by Duke on September 30th,[10] less than 4 weeks after the Update was filed in this proceeding. Notably, over 1000 MW of these new retirements now occur within the

[10] See Duke’s filing in NCUC Docket No. E-7 Sub 1214

next 10 years[11] and would have a substantial impact on the calculation of both avoided energy and avoided capacity costs.

- The 2019 Update does not reflect additional requirements that the NCUC issued in its recent order in Duke's North Carolina IRP proceeding.[12]
- Act 62 includes detailed new requirements for IRP sufficiency that Duke's 2019 update most likely does not comply with.

Second, Duke's rebuttal insinuates that I have claimed many "novel" methodological choices in this proceeding. That is not the case. In fact, my direct testimony never suggested this, but is simply focused on identifying certain practices that may be biased, regardless of when or where they were adopted. In any event, given the closer evaluation Act 62 requires of the utilities' avoided cost calculations and methodologies, Duke's methodological choices should be subject to scrutiny whether or not they represent the company's historical practice.

III. <u>Speculative Risks</u>

Q. Does Duke dispute the Commission's ability to consider of potential risk factors such as cost overruns or environmental adders?

A. Yes. Duke states that calculation of these factors would be "unprecedented" and "prohibited by PURPA."[13]

Q. Did you try to quantify these risk factors?

[11] This includes Allen units 4 and 5 (526 MW total), which are now expected to retire in 2024 instead of the IRP Update assumption of 2028. It also includes Cliffside unit 5, which is not expected to retire in 2026 instead of 2032.
[12] NCUC Docket No. E-100 Sub 157.
[13] Snider Rebuttal, p 14.

A. No. By Duke's own admission, "Mr. Burgess makes no attempt to quantify [these risks] as impacting future system costs."[14] Nor am I suggesting that Duke's avoided cost calculations should include any kind of "adder" to represent these risks.

Q. Do you think these risks are still something that the Commission should consider, even if not directly included in the avoided cost calculation?

A. Yes. The issue of ratepayer risk must be considered under Act 62 and Duke devotes much of its direct and rebuttal testimony to characterizing QF contracts as "risky" for ratepayers. My primary point is that construction of additional utility generation exposes ratepayers to a much wider scope of risks than long-term fixed price contracts. As explained in my Direct testimony, there are a number of places in the avoided cost calculation where methodological choices must be made regarding uncertain inputs and assumptions. This means that there is a range of potential values that could be considered reasonable. Neither end of this range is "correct" but a judgment call must be made by the Commission about where to lean. If there are other risk factors that are not directly reflected in the calculation, they might be worth considering when judging where to lean.

IV. Competitiveness

Q. Does Duke's rebuttal argue that there is robust competition for generation supply in South Carolina?

A. Yes. Duke invokes the CPRE program as evidence of this competition.

Q. Do you agree?

[14] Snider Rebuttal, p 14.

A. No. At the outset, it is important to recognize that Duke is a vertically integrated utility, which means that it is not only has a monopoly as a seller of electricity to retail customers, it also has a monopsony as a buyer of electricity from wholesale suppliers. As such, Duke has substantial discretion over which suppliers can compete in the market. Both QFs under PURPA and the CPRE program are exceptions to this that increase overall competition for generation supply.

Q. Do you view the CPRE program is evidence of a robust competitive process in South Carolina that should be considered as an alternative to PURPA?

A. I believe there are many elements of the CPRE program that reflect a good competitive process and should continue to be pursued. However the CPRE program is also limited in many respects, and thus, should therefore be considered as supplemental to (rather than an alternative to) PURPA in terms of promoting more competition on the supply side.

Q. What are the limitations in the CPRE program for South Carolina?

A. There are several including the following:

- The CPRE process is primarily controlled by the North Carolina Utilities Commission.
- Duke did not meet its goals in Tranche 1 of the program (i.e. not enough projects were selected to sign PPAs) and therefore may not be on track to meet its statutory MW targets.
- Duke is permitted to participate (up to 30% of projects) and therefore the competitive nature of the program is not limited to third party suppliers. In addition, any number of bids may be “asset acquisition” proposals under which Duke purchases the bidder’s facility and incorporates it into the utility’s rate base; and in fact Duke ended up winning almost 45% of the total capacity bids in Tranche 1 of CPRE.

V. <u>Ratepayer Impact</u>

Q. What critique does Duke raise regarding your analysis of the potential cost impact to Duke's customers if SBA's changes are adopted?

A. Duke suggests that my analysis "dodges the question" and does not address the "total impact" of proposed rates.

Q. Is this accurate?

A. No. My analysis was presented as an illustration of the potential impact of one important element of SBA's proposal – deferring adoption of an integration charge. That being said, I have conducted further analysis of other elements of the SBA recommendations, which are presented below. The analysis confirms that even under a high penetration solar QF scenario, the potential impact to revenue requirement is less than 1% for DEC and less than 2% for DEP.

Q. Would SBA's proposal constitute a rate increase?

A. No. The analysis shown below simply indicates the additional payments that QFs would receive under SBA's proposal relative to Duke proposal. As explained elsewhere, I believe SBA's proposal better reflects true avoided costs, as such, these payments would be offset by reduced expenses elsewhere on Duke's system.

	DEC	DEP
MW of Solar (+1500 Scenario)	3020	4610
Percent assumed to be deployed in SC	30%	30%
Capacity Factor (based on a SAT system modeled in SAM)	18.90%	18.90%
MWh output (SC portion)	1,500,010	2,289,750
Integration Charge ($/MWh)	$1.10	$2.39
Total Integration Charge Collected from SC QFs (millions)	$ 1.7	$ 5.5
Duke Proposed Energy Rate Design ($/MWh, levelized)	$29.42	$26.72
SBA Proposed Energy Rate Design ($/MWh, levelized)	$30.49	na
Difference ($/MWh)	$1.06	na

Additional Payment to SC QFs (millions)	$1.59	na
Duke Proposed Capacity Rate ($/MWh, levelized)	$0.73	$1.52
SBA Proposed Capacity Rate ($/MWh, levelized)	$4.45	$3.63
Difference ($/MWh)	$3.73	$2.10
Additional Payment to SC QFs (millions)	$5.59	$4.82
Estimated Annual Revenue Requirement (millions)	$ 1,720	603
Integration Charge (as % of total RevReq)	0.1%	0.9%
SBA Energy Rate Design (incr. as % of RevReq)	0.1%	na
SBA Capacity Rate (incr. as % of RevReq)	0.3%	0.8%
Total Impact of SBA Changes (relative to Duke proposal)	0.5%	1.7%

Q. Are there other potential changes to avoided cost rates not captured in the above analysis that may also be warranted?

A. Yes. As explained in my direct testimony, and the remainder of this surrebuttal, there are several outstanding issues. However, these require more detailed modeling efforts to be undertaken by Duke, which was not possible in the timeframe of this proceeding.

VI. <u>Avoided Energy Cost Modeling</u>

Q. How does Duke respond to SBA's concerns regarding the frequency of negative hourly avoided cost values in its modeling results?

A. Duke explains that negative values occur for a variety of reasons, and provides an example of the impact a QF might have in shifting the start hour for a combustion turbine from one hour to the next, thereby leading to a negative value for the new start hour.

Q. Does this example make sense to you conceptually?

A. Yes, although it is not possible to evaluate whether Duke's claims are true based on the data they have provided. Nor has Duke denied that there are other modeling constraints that artificially drive down avoided cost values (as suggested in my direct testimony).

Q. Are you able to evaluate whether changes to the timing of startups, as suggested by this example, is a major driver of negative values within Duke's model?

A. No. Duke has not provided disaggregated data on hourly unit starts or startup costs that would be needed to accurately evaluate whether this phenomenon is occurring. There may also be other drivers of negative values, such as congestion and/or must-run requirements.

Q. What other factors does Duke say contribute to negative hours?

A. Duke explains that the addition of a 100 MW QF resource would change the hours of pumping and discharge for its pumped hydro facilities. Duke explains that this "frequently drives negative hours, in DEC in particular."[15]

Q. Has Duke provided any data on the modeled dispatch of any individual facilities, including its pumped hydro facilities?

A. No. As a result, I have been unable to evaluate the impact that this could have on the model results, including negative values.

Q. What is Duke's response to SBA's observation that coal units are often the marginal resource in DEC and DEP-East?

A. Duke explains that while coal is often the marginal unit, "cycling restrictions and must run restrictions often prevent them from reducing their output when additional generation is added to the system."[16] As a result, the units that are able to reduce their output are often gas units.

Q. Are these cycling and must-run restrictions on coal units concerning to you?

[15] Snider Rebuttal, p 23
[16] Snider Rebuttal at 26.

A. Yes. I am concerned about whether the inclusion of coal units with these restrictions – particularly the must-run restrictions -- is appropriate and what effect that may have on the model results.

Q. Does the inclusion of these coal units reflect Duke's actual resource plan over the next 10 years?

A. Apparently not. As discussed above, within a few weeks after releasing an IRP that included these coal units, Duke announced the early retirement of over 1000 MW of coal plants in its service territories within the next [10] years. It is not clear how Duke will adjust its resource plan to accommodate these retirements, but what is clear is that the model on which Duke bases its avoided energy calculations no longer reflects Duke's plans for the operation of its system.

Q. What effect might the inclusion of coal units with must-run restrictions have on the model results?

A. I believe it could have the effect of suppressing avoided cost values. As Duke explains, these must-run coal units cannot be displaced even if they are the marginal unit (i.e. higher cost than other units online). As a result, the addition of QF resources often displaces power from lower-cost gas units instead of power from higher-cost coal units. However, the fact that these coal units are online in the first place means that they push down the remaining portion of the generation supply curve. This in turn will affect which gas generation unit is backed down due to the addition of a QF (relative to a scenario where the coal unit was not online). Put differently, if the must-run coal units were not included, the marginal gas unit that is displaced would more likely be a higher-cost, less-efficient gas unit. In that case, the avoided cost may be higher than what is currently modeled.

Q. How could Duke's model input decisions on this issue lead to lower avoided cost values?

A. There are two potential ways this could occur. First Duke could designate certain coal units as must run regardless of their technical operating capabilities. Second, Duke could include coal units in its IRP that are uneconomic and should be retired. Notably, the NCUC in its recent order on Duke's IRP required additional analysis on potential "cost savings attributable to earlier retirement of such plants."[17] Additionally, as noted earlier, Duke has recently announced early retirement of over 1000 MW of coal facilities that were not reflected in 2019 IRP Update.

Q. Has Duke provided detailed information about the cycling and must-run restrictions of its coal units?

A. No.

Q. What do recommend as a remedy to these concerns?

A. As an initial matter, I recommend that Duke provide additional transparency and data on the following:

- Detailed descriptions of must-run and cycling restrictions and the rationale for including these.
- Hourly data on when must-run units are operating.
- Hourly data on pumped hydro dispatch in the base case and change case
- Hourly data on the timing of individual unit starts

[17] NCUC Order Accepting Integrated Resource Plans And Reps Compliance Plans, Scheduling Oral Argument, And Requiring Additional Analyses, Docket No. E-100, Sub 157

Additionally, I recommend that Duke's model be rerun without the must-run coal units included as a sensitivity analysis to determine their effect on avoided energy costs.

Q. What was Duke's response to your concerns regarding the difference in marginal units for DEP-East and DEP-West?

A. Duke explains that the "DEP-East and DEP-West BAAs operate as a single DEP NERC Balancing Authority, and are interconnected through firm transmission interconnects that allow integrated system dispatch of all fleet generating units in DEP-East and DEP-West to serve load in both DEP-West"[18]

Q. Does this mean that the marginal unit will be the same in DEP-East and DEP-West at all times?

A. Not necessarily. While this may be true the majority of the time, it is possible that there are times when the firm transmission capability between the DEP-East and DEP-West areas reaches its limit. In this case there would be a different marginal unit in each area.

Q. Has Duke provided any data or information on the frequency or timing of when this transmission limit has been reached in its model?

A. Not to my knowledge.

Q. What do you recommend to account for this possibility that the marginal unit could be different between the two areas, at least during some hours?

A. Consistent with my direct testimony, I recommend that avoided cost values be calculated for both areas. If there are no times when the transmission limit is reached, then the results should be equivalent. However, if there are in fact times when the limit is reached, then the results would be more accurate. This would also be consistent with Act 62, which allows

[18] Snider Rebuttal p 27

for more location-specific pricing which "may account for differences in costs avoided based on the geographic location and resource type."[19]

VII. Rate Design

Q. What reactions does Duke provide to SBA's proposed alternative rate design for DEC?

A. Duke implies that SBA's proposal:

a) is too focused on the specific operating characteristics of solar QFs

b) ignores Duke's proposed design which intended to offer higher prices during times of higher value

c) is not administratively manageable

Q. Do you agree with this characterization?

A. No. Regarding the first point (i.e. focus on solar QFs), our proposed alternate time periods are agnostic as to the underlying technology of the QF resource. The proposed time periods are nearly identical to Duke's, except that they provide additional price accuracy by breaking two of Duke's proposed time periods into two parts, thus providing additional granularity. While our proposal may be better for solar QFs, it is intended to better reflect the value of energy delivered from any QF resource. Regarding the second point (i.e. ignores Duke's design principles), the SBA proposal actually reinforces Duke's design principles rather than ignoring them. It provides more granularity in pricing and less averaging of values. Regarding the third point (administrability), SBA's proposal only adds two time periods to the existing nine periods. This has not caused confusion for the industry

[19] Act 62

that SBA represents and since prices are fixed for the PPA term there should be no "confusion" if future price changes were to occur that affect future QFs.

VIII. Large PPAs with Storage

Q. What does Duke say regarding the fact that a technology-specific approach for avoided costs is not appropriate for facilities that include storage?

A. Duke concedes that this "is a fair point"[20] and agrees that the avoided energy rates should reflect the characteristics of a storage device. However, the Company fails to provide any solutions that reflect this and continues to support the application of a solar-specific generation profile, even to solar QFs that include storage.

IX. Avoided Capacity Cost Assumptions

Q. Does Duke dispute your critique of the economies of scale adjustment to the capital cost of a new peaker?

A. Yes. The companies explain that "the infrastructure cost per CT would be lower for a four-unit site compared to a single CT site."[21]

Q. According to their 2019 IRPs, do either DEC or DEP plan to construct a four-unit plant as their next peaker addition?

A. No. According to Snider's Rebuttal testimony both companies are planning two CT additions as their next capacity additions rather than four. As Snider states: "DEC's 2019 IRP shows a block of two F-class CTs projected in 2026" and "DEP's 2019 IRP shows two F-class CTs in 2028." Thus, in both cases, the concept of a 4-unit plant is not even reflected in the utilities own planning models.

[20] Snider Rebuttal, p 34
[21] Snider Rebuttal at 46.

Q. If the Commission accepts Duke's assumed capital costs for a new peaker, what would be a fair way to ensure that QF resources are competing on a level playing field with utility-owned generation?

A. At the same time the Commission approves avoided capacity rates in this proceeding, the Commission could also adopt a strict cap on rate recovery for any future utility-owned generation capacity costs. This cap should be set at Duke's proposed level of capital costs for a new peaker – specifically, $[redacted]/kW in 2019 dollars (indexed for inflation). This would ensure that both utility-owned generation and competitive third-party generation (in the form of QFs) are provided an equivalent level of compensation for providing capacity to Duke's customers.

Q. Do you agree with Duke's explanation that transmission interconnection costs are already fully included in the peaker capital costs?

A. Not in all cases. Duke points to the EIA documentation on this matter, which does appear to include some interconnection costs for the plant switchyard and "interconnection to an 'adjacent' (e.g. within a mile) of the plant."[22] However it specifically "does not include significant transmission system upgrades."[23] Thus, if the plant is more than a mile from the point of interconnection, these costs could be significantly higher. Additionally, it is possible that there would significant transmission upgrades for any plant that do not fall within the category of network system upgrades.

---

[22] EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants, Appendix B, at 2-7, *available at* https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf
[23] See above.

Q. Do you agree with Duke's assertion that "utilities are not obligated to pay QFs for capacity that exceeds system needs, such as for resale in a capacity market under PURPA"?

A. I don't disagree with this. However, it is still worth noting that, regardless of what is required under PURPA, there is value from the capacity that QFs do provide, whether that is in the form of avoided purchases or increased sales opportunities. Notably, Duke did not dispute that there may be avoided capacity costs related to near-term purchases, with the exception of "existing capacity arrangements."[24]

Q. Did your direct testimony assume that QFs will renew their contracts as Duke claims?

A. No. Duke misinterpreted my testimony in this regard. I did not actually quantify or propose that potential contract renewals be taken into account for the purpose of establishing rates under PURPA. I was simply making the observation that this is possible and may be a qualitative factor the Commission could consider when assessing whether Duke's proposed avoided cost rates are appropriate.

X. Seasonal Allocation of Capacity Value

Q. In your direct testimony, you made a preliminary recommendation of the seasonal allocation for capacity value based simply upon historical load, correct?

A. Yes. This was done as a simple first approximation based upon available data and accelerated time constraints of this proceeding that prevented me from conducting a more thorough analysis.

Q. Do you believe this preliminary method could be improved upon?

[24] Snider Rebuttal at page 54.

A. Yes. As I stated in my direct testimony, "I may propose a more specific allocation later."[25]

Q. What specific critiques did Duke raise with your preliminary method?

A. Duke's primary concerns were that this approach 1) "did not take into account the impact of must-take solar output" and 2) "incorrectly included an extremely broad number of hours by using the 'top 5% of load hours.'"[26]

Q. Do you agree with these critiques?

A. I do, with some qualifications that I will explain below.

Q. What specific changes would you recommend to address these issues?

A. To address the first issue, I would update my analysis to reflect net load (rather than just load) by adjusting the historical load profiles to account for must-take solar output. To address the second issue, I would adjust the number of hours to reflect a narrower band of top load hours.

Q. Have you now performed this analysis?

A. Yes. The results are provided in the table below.

Q. What level of must-take solar did you use to calculate net load?

A. Consistent with ORS' recommendation, I believe it is appropriate to consider the "Existing plus Transition" level of solar for the current proceeding since it best reflects the amount of solar that is either currently online or will be in the near future. Thus, I have subtracted from the hourly load values and amount of generation consistent with 840 MW of solar for DEC and 2950 MW of solar for DEP.[27] These values could be updated in future avoided

[25] Burgess, Direct, p 53.
[26] Snider Rebuttal, p 69.
[27] Hourly solar output profiles were estimated for a South Carolina location using the National Renewable Energy Laboratory's PV Watts simulator tool.

cost calculations as additional solar comes online but they are appropriate for the current proceeding.

Q. What number of hours is appropriate to consider when evaluating loss of load risk?

A. While there are metrics commonly used in the industry (e.g. 1 day in 10 years), these have always been somewhat subjective and are the result of engineering judgement calls that attempt to balance a tolerable level of risk with the significant cost of reducing that risk. Thus, while there is no objectively "correct" value, I am willing to accept Duke's suggestion that my initial assessment may have included an overly broad number of hours.

Q. What adjustment did you make to the number of hours considered to be high loss of load risk for seasonal allocation purposes?

A. I reduced the number of hours by a factor of 50 – that is from the top 5% of load hours to the top 0.1% of load hours.

	DEC		DEP	
	Summer	Winter	Summer	Winter
Historical Load Only (top 5%)	82%	18%	77%	23%
Adjusted for Net Load (Existing + Transition, top 5%)	79%	21%	63%	37%
Adjusted for Net Load and 0.1% of Top Load Hours	58%	42%	4%	96%

Q. What other factors are important in determining loss of load risk, and the corresponding seasonal allocations for capacity value?

A. As explained in my direct testimony, other important factors include future load shapes, future demand response resources, and the availability of neighbor assistance – especially from summer peaking utilities.

Q. Did Duke adequately respond to your requests for more information on these issues?

A. No. Despite multiple requests from SBA, Duke refused to provide any revised analysis with changes to these input assumptions.[28] For example, regarding a request to model increased winter demand response, Duke states in its Rebuttal, "The Companies did not run this scenario since it is irrelevant given that large quantities of demand response participation are not achievable within such a short timeframe nor are they appropriate to assume in this case."[29]

Q. Do you agree that this scenario is irrelevant?

A. Not at all. The purpose of requesting this scenario was not based on whether a larger quantity of demand response should be considered feasible. Rather, this was simply intended as a sensitivity case to see what the effect would be on the Company's assumed seasonal allocations. Even a more modest increase in winter demand response might have significant effects and may be worth further consideration in this proceeding and others. However, Duke appears unwilling to provide this information.

XI. <u>Integration Services Charge</u>

Q. Do you agree with Duke's claim (on page 85 of Mr. Snider's Rebuttal Testimony) that the proposed cap on the Integration Services Charge represents a "balanced" solution for both QF and customer interests?

[28] See Duke's response to SBA RFP 3-4.
[29] Snider Rebuttal, p 66.

A. No. Duke presents a false notion of balance on this issue. As addressed in my Direct testimony, the integration charge represents a potential savings to customers on the order of <1% in an effort to cover costs that may not even materialize to any significant degree. By contrast, the proposed cap is so high as to render future projects unfinanceable and would place a significant barrier on new QF development.

Q. What restrictions does Duke's coal fleet have that could affect its ability to respond to solar volatility?

A. As explained by Duke, many of its coal units have cycling and must-run restrictions that prevent them from ramping up or down.[30] This likely means that other units may need to be committed to provide operating reserves to respond to solar volatility. If these inflexible coal units were not online, then the additional gas units committed in their place may have the flexibility needed to provide integration services at a lower overall cost. As such, it is logical to assign some portion of any modeled integration costs to inflexible coal units, rather than attributing them solely to solar, since these costs may be higher when the coal units are operating.

Q. Do you agree with Duke's suggestion that compensation for additional ancillary services, beyond mitigation of those caused by solar, should not be considered?

A. No. Duke argues that such a compensation structure was "not envisioned by PURPA"[31] however this does not mean it is impermissible or should not be encouraged. Whatever Duke's interpretation of PURPA, Act 62 specifically requires the utility to calculate the value of "ancillary services provided by or consumed by small power producers." S.C. Code Ann. § 58-41-20(B)(3). There is no basis for treating ancillary services provided by

[30] See Snider Rebuttal at p 26.
[31] Snider Rebuttal, p 88.

QFs differently from those allegedly consumed by them. Furthermore, Duke argues that providing these services "would [not] be economic under a must take PURPA contract."[32] However, there is no way to know if this is true unless the option is offered at a fair compensation rate to potential QF resource providers.

Q. Based on your analysis of Duke's avoided cost methodologies, including the assumptions and inputs, what avoided cost rates does SCSBA propose that the Commission adopt in this proceeding?

A. First it must be noted that, as described above, Duke's avoided cost methodologies were not reasonably transparent and, lacking access to Duke's proprietary production cost modeling, it was not possible for SCSBA to calculate avoided cost rates using precisely the same methodologies employed by Duke. As discussed in my testimony, there are many methodological flaws in Duke's avoided cost calculations. In some cases it is possible to quantify the impact of those flaws on Duke's rates; in other cases it would only be possible to precisely quantify those effects by re-running Duke's production cost simulation and other modeling, and using those results to calculate rates.

In my view, the most reasonable approach for the Commission to take, if it agrees that Duke's methodologies are flawed, would be to direct Duke to address these flaws and recalculate its rates. In my experience this is the approach usually taken by other state utilities commissions in situations like this.

However, if the Commission does not wish to take this approach, SCSBA has provided a set of proposed avoided cost rates, based on (1) where possible, a quantification of the impacts of Duke's methodological flaws, and (2) where quantification is not possible, a

[32] See above.

reasonable estimate of the impact based on my experience and expertise. SCSBA's proposed rates are attached in Exhibit **Burgess 2**.

Burgess Exhibit 2 - Summary of SBA Proposed Rates

Capacity Pricing Periods

Note: SBA has not proposed any changes to Duke's proposed time periods indicated below

Capacity Rates																								
Independent Capacity Price Blocks			1. Summer Capacity							2. Winter Capacity (AM)									3. Winter Capacity (PM)					
Company			DEC		DEP					DEC		DEP							DEC		DEP			
10-Yr Rate (cents/KWH)			0.86		0.00					3.99		11.36							1.29		4.87			
DEC / DEP Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jul - Aug)																	1.Summer							
Winter (Dec - Mar)							2.Winter (AM)												3.Winter (PM)					

Rate Summary Table – Capacity (SBA Proposed – Direct Testimony)

DEC

Season	Summer	Winter	Winter
Period	PM	AM	PM
Allocation	82%	14%	5%
10-Yr Rate (cents/KWH)	23.12	2.60	0.87

DEP

Season	Summer	Winter	Winter
Period	PM	AM	PM
Allocation	77%	17%	6%
10-Yr Rate (cents/KWH)	37.31	5.71	1.90

Rate Summary Table – Capacity (SBA Proposed – Revised Seasonal Allocation)

DEC

Season	Summer	Winter	Winter
Period	PM	AM	PM
Allocation	58%	32%	11%
10-Yr Rate (cents/KWH)	16.35	6.07	2.02

DEP

Season	Summer	Winter	Winter
Period	PM	AM	PM
Allocation	4%	72%	24%
10-Yr Rate (cents/KWH)	1.94	23.84	7.95

Rate Summary Table – Energy (Duke Proposed)

<table>
<tr><th colspan="19">Energy Rates</th></tr>
<tr><td>Independent Energy Price Blocks</td><td colspan="2">1.Summer Premium Peak (PM)</td><td colspan="2">2.Summer On-Peak (PM)</td><td colspan="2">3.Summer Off-Peak</td><td colspan="2">4. Winter Premium Peak (AM)</td><td colspan="2">5.Winter On-Peak (AM)</td><td colspan="2">6.Winter On-Peak (PM)</td><td colspan="2">7.Winter Off-Peak</td><td colspan="2">8.Shoulder On-Peak</td><td colspan="2">9.Shoulder Off-Peak</td></tr>
<tr><td>Company</td><td>DEC</td><td>DEP</td><td>DEC</td><td>DEP</td><td>DEC</td><td>DEP</td><td>DEC</td><td>DEP</td><td>DEC</td><td>DEP</td><td>DEC</td><td>DEP</td><td>DEC</td><td>DEP</td><td>DEC</td><td>DEP</td><td>DEC</td><td>DEP</td></tr>
<tr><td>10-Yr Rate (cents/KWH)</td><td>4.58</td><td>3.30</td><td>4.48</td><td>3.11</td><td>2.60</td><td>2.68</td><td>5.04</td><td>3.58</td><td>4.61</td><td>3.54</td><td>4.15</td><td>3.42</td><td>2.70</td><td>2.75</td><td>3.39</td><td>2.98</td><td>2.28</td><td>2.26</td></tr>
</table>

<table>
<tr><th>DEC Energy Hour Ending</th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th><th>11</th><th>12</th><th>13</th><th>14</th><th>15</th><th>16</th><th>17</th><th>18</th><th>19</th><th>20</th><th>21</th><th>22</th><th>23</th><th>24</th></tr>
<tr><td>Summer (Jun-Sep)</td><td colspan="12">3.Off</td><td colspan="4">2.On (PM)</td><td colspan="4">1.Premium</td><td colspan="2">2.On (PM)</td><td colspan="2">3.Off</td></tr>
<tr><td>Winter (Dec-Feb)</td><td colspan="5">7.Off</td><td>5.On</td><td colspan="3">4.Premium</td><td>5.On</td><td colspan="7">7.Off</td><td colspan="5">6.On (PM)</td><td colspan="2">7.Off</td></tr>
<tr><td>Shoulder (Remaining)</td><td colspan="6">9.Off</td><td colspan="4">8.On</td><td colspan="6">9.Off</td><td colspan="7">8.On</td><td>9.Off</td></tr>
<tr><th>DEP Energy Hour Ending</th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th><th>11</th><th>12</th><th>13</th><th>14</th><th>15</th><th>16</th><th>17</th><th>18</th><th>19</th><th>20</th><th>21</th><th>22</th><th>23</th><th>24</th></tr>
<tr><td>Summer (Jun-Sep)</td><td colspan="13">3.Off</td><td colspan="3">2.On (PM)</td><td colspan="4">1.Premium</td><td>2.On</td><td colspan="3">3.Off</td></tr>
<tr><td>Winter (Dec-Feb)</td><td colspan="4">7.Off</td><td colspan="2">5.On (AM)</td><td colspan="3">4.Premium</td><td colspan="2">5.On (AM)</td><td colspan="7">7.Off</td><td colspan="4">6.On (PM)</td><td colspan="2">7.Off</td></tr>
<tr><td>Shoulder (Remaining)</td><td colspan="5">9.Off</td><td colspan="5">8.On</td><td colspan="7">9.Off</td><td colspan="6">8.On</td><td>9.Off</td></tr>
</table>

<u>Rate Summary Table – Energy (SBA Proposed)</u>

DEP: No Change

DEC: (highlights indicate modifications)

DEC	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)	Off							On (AM)					On (PM)				Premium				On (PM)		Off	
Winter (Dec-Feb)	Off					On (AM)	Premium			On (AM)	Off							On (PM)					Off	
Shoulder (Remaining)	Off						On				Midday						On							Off

Period	Cents/kWh
1_DEC_Summer_Prem-Peak	4.58
2_DEC_Summer_PM-Peak	4.48
3_DEC_Summer_OffPeak	2.49
4_DEC_Winter_ Prem-Peak	5.04
5_DEC_Winter_ AM-Peak	4.61
6_DEC_Winter_ PM-Peak	4.15
7_DEC_Winter_ OffPeak	2.70
8_DEC_Shoulder_Peak	3.39
9_DEC_Shoulder_OffPeak	2.13
Summer AM Peak (New)	2.95
Shoulder Midday (New)	2.77